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EFFICIENCY AND COST BENEFIT ASSESSMENTS ON A TYPICAL 600MW COAL FIRED BOILER POWER PLANT

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ABSTRACT

The overall efficiency of a coal fired boiler power plant ranges from 34 to 40% considering the boiler efficiency and turbine cycle heat rate. A comparative study is made applying the necessary corrections while evaluating the boiler efficiency (using the direct and indirect methods) and the turbine cycle heat rate for the design and actual operating conditions of a typical 600MW coal fired boiler power plant. Heat rate deviation is assessed when the unit in live operating conditions is deviated from the design operating conditions. Finally, cost benefit and CO2 reduction analyses are performed fromthe estimated heat rate deviation for abundantly available coals in India. Curative actions and applicability to conventional and non-conventional fuels, supercritical, combined cycle, nuclear power plants are highlighted for efficient, economical and eco-friendly operation of the plant.

KEYWORDS: Coal Fired Boiler, Cost Benefit, Direct Method, Efficiency, Heat Rate Deviation; Indirect Method, Power Plant & Turbine Cycle Heat Rate

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Original Article

1. INTRODUCTION

Power plants play a major role in the country's economic growth. In developed countries the individual power consumption is very high (12071kwh/year in USA) when compared to that of developing countries (1122kWh/year in India)[https://www.cia.gov/library/publications/the-world-factbook/rankorder/2233rank.html]. This is mainly due to high power consumption in industries. Less power consumption indicates low growth in industries and less job opportunities. India has developed from 1362MW(in 1947at its independence) to 3,43,899MW (in June 2018 having contributions:58% Coal, 20% renewable, 13% hydro, 7% gas, 1.8% Nuclear, 0.2% Oil)[https://powermin.nic.in/en/content/power-sector-glance-all-india/]. In the present scenario 65% of electricity is generated from thermal power plants utilizing more than 80% of coal in india. For economical operation there is a need to improve the efficiency of power plants. It is noted that 80% of the commissioned power capacity is between 210 to 660MW; and theuneconomical operations of old units of 25 to 300MW are to be scraped [https://npp.gov.in/public-reports/cea/daily/dgr/22-08-2018/dgr1-2018-08-22.pdf]. However, 500 to 660MWunits are producing more than half of the power required in India. Cost benefit analysis on power plants indicatesa reductionof heat rate deviation which decreases operating costs, coal consumption, CO_2 emissions and improves overall efficiency [1-3]

1.1 Operations in a Coal Fired Boiler Thermal Power Plants

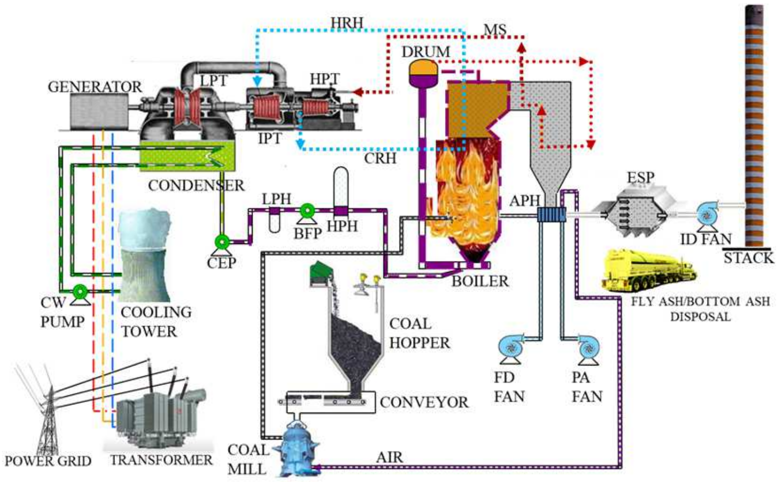

Figure 1: A Typical Coal Fired Thermal Power Plant System

Figure 1 shows a typical thermal power plant operating with coal as a fuel. The coal handling plant transfers coal through belt conveyor to coal hopper, then it supplies to a coal mill through conveyor. A coal mill pulverizes the coal to fine powder. The air supplied from primary air fan forces this pulverized coal to the boiler through burner system. Forced draft fan pumps, airinto boiler cavity through windbox. The fuel gun in the burner system makes the air and coal mixture burn through a chemical reaction producing heat and combustion products (flue gases and ash). The heat produced is absorbed by water supplied from a boiler feed pump. Water runs through waterwall tubes and converts to steam. Water and steam mixture enter the boiler drum. The steam from boiler drum enters into super heater coils and goes to the high pressure turbine (HPT) through main steam line (MS). The steam is partly expanded in HP turbine to avoid formation of water vapour. This water is reheated in the boiler re-heater coils and goes to intermediate pressure turbine(IPT) through hot reheat line(HRH) and then expands in IP turbine and low pressure turbine (LPT) and power is produced. The exhaust steam from the low pressure turbine is condensed to water in condenser using cooling water. The heated up cooling water is cooled down by a cooling tower and is recirculated by cooling water pump. The condensed steam from LP turbine is pumped by condensate extraction pump through low pressure heaters which pre-heats the water by extraction steam from LP turbine. The pre-heated water is supplied through de-aerator to boiler feed pump for raising its pressure. The high pressure water is further heated by extracting steam from IP turbine and HP turbine in high pressure heaters and then enters the boiler.

1.2 Unit Operating Conditions

Table 1: Main Operating Conditions of a Typical 600MW Thermal Plant

Main Operating Conditions	Power Output (MW)	Main Steam		Cold Reheat		Hot Reheat		Feed Water	
		m_i T/h	h_i kJ/kg	m_i T/h	h_i kJ/kg	m_i T/h	h_i kJ/kg	m_i T/h	h_i kJ/kg
100% BMCR/ VWO	648	2028	3397	1719	3048	1719	3534	2028	1236
100% TMCR	600	1849	3397	1576	3033	1576	3537	1849	1206
3% Make Up Water	600	1865	3397	1581	3033	1581	3537	1865	1207
TRIAL RUN	600	1902	3397	1611	3036	1611	3536	1902	1214
80% TMCR	480	1465	3418	1465	3048	1267	3544	1465	1140
60% TMCR	360	1123	3451	1123	3085	0984	3523	1123	1069
50% TMCR	300	0957	3466	0957	3102	0845	3498	0957	1028

Table 1: Contd.,

40% TMCR	240	0793	3471	0793	3111	0704	3468	0793	0980
All HP heaters bypassed	600	1619	3397	1619	3054	1592	3536	1619	0769
NO.1 HP heater bypassed	600	1751	3397	1751	3041	1607	3536	1751	1065
Extraction Steam	600	1997	3397	1997	3030	1599	3537	1997	1221
Live Near 100% TMCR	576	1798	3392	1552	3046	1552	3515	1728	1221

To achieve the maximum possible efficiency the power plant needs a specification of operating conditions through experimental trials on a replica module or similar model in a controlled laboratory or the data from the running or live operating power plants. Data of pressure, temperature, flow rates etc. Guides a power plant to operate in the most effective manner. The design operating conditions are classified on the boiler rated capacity, turbine rated capacity, load applied by power grid, feed water heaters conditionand co-generation.

Table 2: Ultimate Analysis Report on Various Types of Coal

Type of Coal	Design Coal	Indian Lignite Coal	Semi-Bituminous Coal	Bituminous Coal	Worst Coal
GCV (Kcal/kg)	3500	4300	4410	5800	3140
Carbon (%)	35.64	37	43.81	59	32.2
Hydrogen (%)	2.48	2.9	2.92	3.1	2.32
Nitrogen (%)	0.68	1.1	1.45	1.1	0.65
Oxygen (%)	5.7	4.5	11.9	10.4	7.33
Sulphur (%)	0.5	1.5	0.02	1.4	0.5
Moisture (%)	10	17	10.75	12.9	12
Ash (%)	45	36	29.15	12.1	45

Figure 2: Types of Coal and Mining Depth

When a boiler operates at its maximum ratecapacity, itit is called 100%BMCR or V. O. All valves of the turbine are to be fully opened to generate more power than its rated capacity. Similarly when a turbine operates at its maximum rated capacity it called 100%TMCR (600MW). The grid load on the plant varies seasonally. During the summer the grid load is maximized and the plant operates at 100%BMCR. When the grid load equals the turbine maximum rated capacity, it is full load (600MW). When the grid has 40%load the turbine operates at 40% and its rated power is 240MW. When the grid load is above 100%BMCR it overloads plant system. When it falls below 40%TMCR, efficient and economical operations of the plant are not possible. When high pressure feed water heaters underperform or malfunction then plant shall operate by hp heaters bypassed. Also, whensome of the steam is extracted from turbine system for supply to other units or for co-generation then extraction steam condition occurs. The main operating conditions of a typical 600MW

power plant are presented in Table 1. The ultimate analysis report of Table 2 and Figure 2 on different types of coal helps the plant operator to opt fuels close to the design fuel. The boiler efficiency and turbine heat rate for operating conditions in Table 1 with the type of fuel in Table 2 can have 60 multiple values.

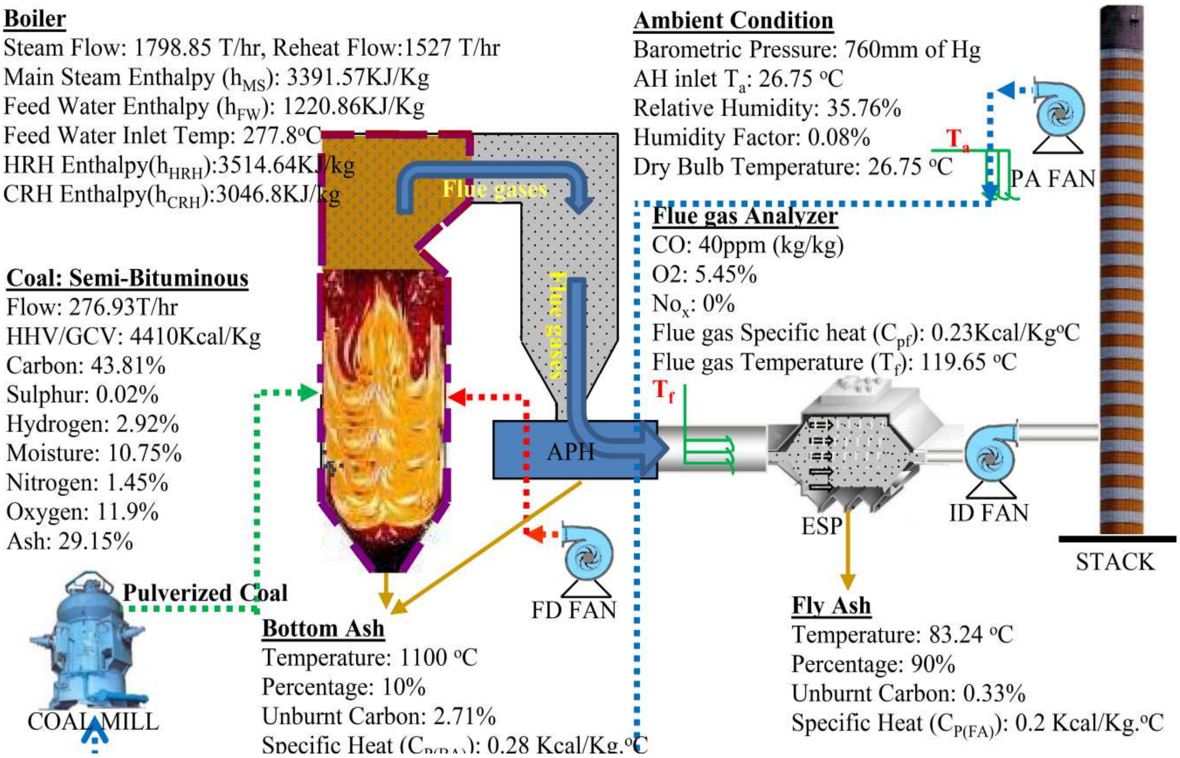

Figure 3: Schematic of a Typical 600MW Boiler with Semi-Bituminous Coal as Pulverized Fuel

A schematic of a typical 600MW boiler with semi-bituminous coal as pulverized fuel is shown in Figure 3. The energy balanceof the coal fired steam power plant in Figure 4 shows the conversion of electrical power from the 100% chemical energy of design coal. The mechanical losses of steam turbine are found to be negligible.

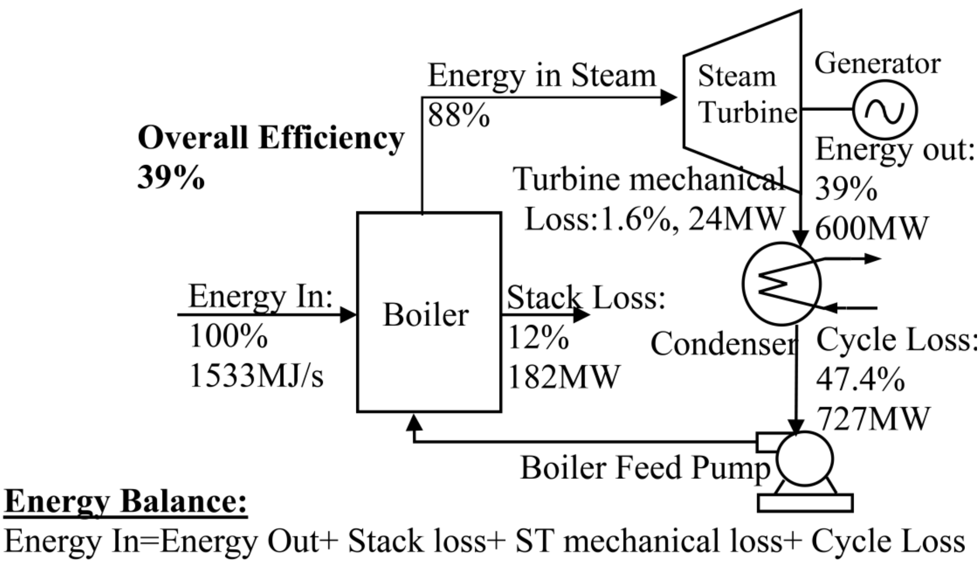

Figure 4: Energy Balance for Coal Fired Steam Power Plant with Design Coal Flow 376.9T/h

1.3 Objectives of the Present Study

In this paper a comparative study is made initially on the boiler efficiency using direct and indirect methods taking design coal as reference. The turbine cycle heat rate is evaluated atthe 100% TMCR conditionby dividing the heat input to steam bya boilerwitha net turbine power output. Turbine cycle heat rate is divided by boiler efficiency to estimate the unit heat rate. The overall efficiency of the plant is found by dividing the ideal unit heat rate of 860kcal/kWh withassessedunit heat rate. Heat rate deviation for live operating plant is found by applying the necessary correction factors and estimated the cost of heat rate deviation and increase in CO_2 production. Curative actions are proposed for reduction of plant heat rate and CO_2considering various types of coal in India. This paper highlights on the applicability of various carbon compound fuel powered plants, combined cycle power plant consisting steam and gas turbines, nuclear power plants.

2. BOILER EFFICIENCY

Direct method (input-output method) and indirect method (energy balance method)[4] are being used for evaluation of the boiler efficiency. In direct method, the boiler efficiency (η_{boiler}) is the ratio of energy absorbed by fluid flowing through boiler(output) to the chemical energy of the fuel (input):

$$\eta_{boiler} = \frac{m_{FW}(h_{MS} - h_{FW}) + m_{CRH}(h_{HRH} - h_{CRH})}{m_{Coal} \times GCV_{Coal}} \times 100 \tag{1}$$

Indirect method for efficiency evaluationrequires chemical analysis of fuel, mass flow rates, temperatures and pressures of involving parameters. This method estimates boiler efficiency (%) by deducting %heat losses and superimposing %credits from 100%.

$$\eta_{boiler} = \left(1 - \frac{(Energy_{losses} - Energy_{credits})}{Energy_{input}}\right) \times 100 \tag{2}$$

Srinivas et al. [1] have hinted that boiler efficiency by the direct method is simple but unable to provide the plant operators about the root cause of lowering the efficiency of the system, which may sometimes mislead. In such a situation, indirect method (heat balance method/energy balance method) seems to be reliable.

The boiler efficiency by direct method for live plant near 100%TMCR with semi-bituminous coal with GCV of 4410kcal/kg or 18433.8kJ/kg is worked out to be 90.55%. For the design coal flow of 354.29 T/h, the boiler efficiency of 87.87% is taken as reference in the cost benefit and CO_2 reduction analyses for coals in Table 2. Boiler efficiency is evaluated and presented in Table 3. Evaluation of boiler efficiency by indirect method requires the results ofpsychometric analysis, fuel ultimate analysis, flue gas analysis, ash analysis, boiler and equipment design specifications. Figure 3gives the data for a live operating plant operating near 100%TMCR with semi-bituminous coal. As per ASME PTC 4 [4], heat balance method provides the boiler efficiency by considering various percentage heat losses and credits. Sinivas et al. [1] and Nag [5] have presented formulae for various heat losses. The additional losses introduced in [https://www.scribd.com/document/253990874/Power-Plant-Commissioning-pdf] are as follows.

$$\text{Heat loss due toIncomplete combustion} = \left(m_{dfg} \times \frac{CO_{ppm} \times 10^{-6} \times GCV_{CO}}{GCV_{Coal}} \times 100\right) \tag{3}$$

$$\text{Heat loss due to unburnt carbon in fly ash} = \left(\frac{BA\% \times Ash\% \times Carbon_{BA}\% \times GCV_{Carbon}}{GCV_{Coal}} \times 100\right) \tag{4}$$

$$\text{Heat loss due to unburnt carboninbottom ash} = \left(\frac{FA\% \times Ash\% \times Carbon_{FA}\% \times GCV_{Carbon}}{GCV_{Coal}} \times 100\right) \quad (5)$$

$$\text{Sensible heat loss due to fly ash} = \left(\frac{FA\% \times Ash\% \times C_{P(FA)} \times (T_{FA} - T_a)}{GCV_{Coal}} \times 100\right) \quad (6)$$

$$\text{Sensible heat loss due to bottom ash} = \left(\frac{BA\% \times Ash\% \times C_{P(BA)} \times (T_{FA} - T_a)}{GCV_{Coal}} \times 100\right) \quad (7)$$

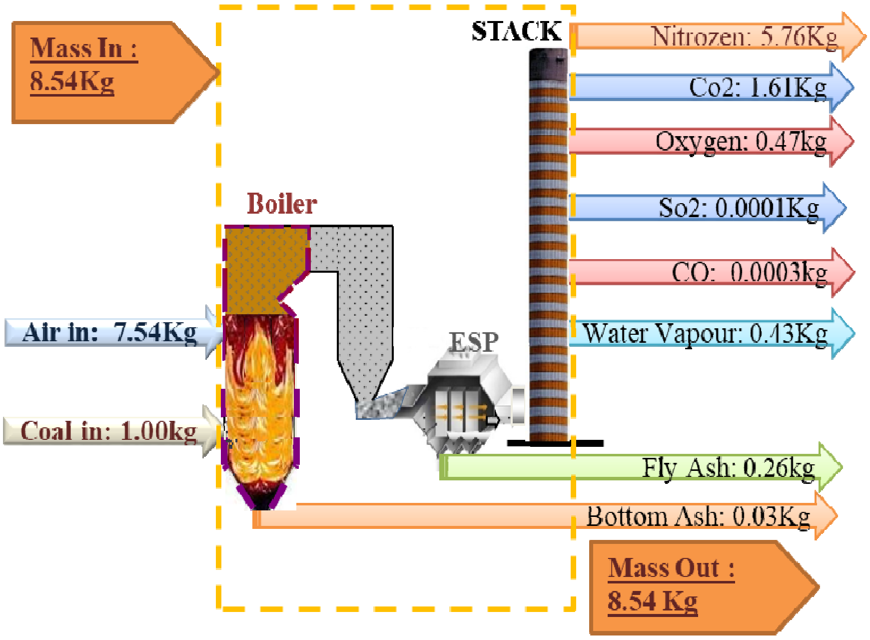

Figure 5: Mass Balance for 1 Kg of Semi-Bituminous Coal Burnt

When complete combustion takes place, water vapour, ash and dry flue gases become combustion products. The mass of the dry flue gases (m_{dfg}) is the sum of the mass of combustion gases (Carbon dioxide, Sulphur dioxide, Nitrogen, Oxygen) excluding water vapour (see Figure 5). But when incomplete combustion takes place Carbon monoxide, Nitrous oxides (NOx) and Acid causing substance like SOx are present. CO is present due to less supply of oxygen. NOx is due to very high combustion temperatures above 1100^{o}C and Sulphuric acid from SOx is due to less dispersion space and high water vapour [6]. Mass of dry flue gases can be computed by neglecting water vapour present and mass of solid combustion products [https://beeindia.gov.in/sites/default/files/4Ch1.pdf].

Various heat losses accounted in the boiler efficiency evaluation are presented below

Theoritical Air required, TAR=5.58 kg/kg of fuel

Excess Air Supplied, EA=35.05%

Actual Air Supplied, AAS=7.54 kg/kg of fuel

Mass of the dry flue gasses, m_{dfg}= AAS +1= 8.54 kg/kg of fuel

Heat loss due to dry flue gases: $Loss_1$=3.96%

Heat loss due to moisture formed from H2 present in fuel: $Loss_2$=3.73%

Heat loss due to moisture in fuel: $Loss_3$=1.53%

Heat loss due to moisture presesnt in air: $Loss_4$=0.06%

Heat loss due to incomplete combustion: $Loss_5$=0.02%

Heat loss due to unburnt carbon in bottom ash: $Loss_6$=0.15%

Heat loss due to unburnt carbon in fly ash: $Loss_7$=0.16%

Heat loss due to sensible heat in bottom ash: $Loss_8$=0.1%

Heat loss due to sensible heat in fly ash: $Loss_9$=0.22%

Heat loss due to convection and radiation from asme ptc 4.1 amba curve: $Loss_{10}$=0.16%

Heat credit due to dry air entering the boiler =0.38%

Heat credit due to moisture in entering air =0.01%

Heat credit due to sensible heat in fuel=0.01

Heat credit due to coal mill=0.19%

Heat credit due to seal air fan=0.01%

Net heat credits=0.6%

$$\eta_{boiler} = 100\% - \sum_{i=1}^{10} Loss_i + \text{ Net heat credits} = 90.56\% \quad (8)$$

Table 3: Boiler Efficiency for Various Types of Coal Near 100%TMCR Live Operating Condition

Description	Design Coal	Semi-Bituminous Coal	Bituminous Coal	Lignite Coal	Worst Coal
Fuel Consumption (T/h)	354.29	276.93	207.46	286.92	399.11
TAR (kg/kg)	4.77	5.58	7.53	5.17	4.25
EA (kg/kg)	35.05	35.05	35.05	35.05	35.05
AAS (kg/kg)	6.44	7.54	10.17	6.98	5.73
$LOSS_1$ (%)	4.35	3.96	3.94	3.79	4.38
$LOSS_2$(%)	3.99	3.73	3.01	3.80	4.16
$LOSS_3$ (%)	1.79	1.53	1.39	2.47	2.39
$LOSS_4$ (%)	0.06	0.06	0.06	0.05	0.06
$LOSS_5$ (%)	0.02	0.02	0.02	0.02	0.02
$LOSS_6$ (%)	0.29	0.15	0.05	0.19	0.32
$LOSS_7$(%)	0.31	0.16	0.05	0.20	0.34
$LOSS_8$(%)	0.1	0.1	0.02	0.1	0.1
$LOSS_9$(%)	0.39	0.22	0.06	0.25	0.43
$LOSS_{10}$(%)	0.16	0.16	0.16	0.16	0.16
Credits (%)	0.6	0.6	0.6	0.6	0.6
Boiler Efficiency (%)	89.12	90.55	91.84	89.57	88.18

With inclusion of net heat credits, the boiler efficiency evaluated by the indirect method closely matches with that of the direct method. Considering the same ambient conditions, flue gas analyser report, fly ash and bottom ash conditions as in Figure 3and specifying thefuel consumption rate and the data of ultimate analysis report in Table 2,the boiler efficiencyisevaluated for various types of coal and presented in Table 3. Usage of bituminous coal leads to higher boiler efficiency.

Table 4: Expressions for the Boiler Efficiency Correction

Variable (x)	ξ	Correction (C_f)
Moisture in coal (%),x∈ [5,15]	2.02815-0.202088x	$0.0478\xi^2 - 0.9508\xi + 0.0015$
Hydrogen in (%), x∈ [1,5]	1.68056-0.540476x	$-0.369\xi^2 - 2.4963\xi + 0.8754$
Air absolute Humidity (%), x∈ [0.015,0.045]	2.00938-67.0464x	$-0.1258\xi - 0.0002$
Air inlet temperature at Air-heater (^{0}C),x∈ [21,62]	2.00519-0.0483254x	$-0.0152\xi^2 - 0.6686\xi + 0.007$
Feed Water Inlet temperature (^{0}C), x∈ [220,324]	5.22058-0.0191613x	$0.2708\xi^2 - 0.6249\xi - 0.038$
Ash in Coal (%), x∈ [30,62]	2.78071-0.0610689x	$0.0114\xi^2 - 0.0828\xi + 0.0026$
HHV of Coal(kcal/kg), x∈ [3164,3824]	-10.0262+0.0028634x	$0.0389\xi^2 - 0.3648\xi - 0.0051$

When live operating conditions (feed water inlet temperature, ambient conditions, fuel/flue-gas/ash chemical composition) differ from the design operating conditions (100%TMCR with design coal), the necessary corrections to boiler efficiency are made for moisture in coal, hydrogen in coal, air absolute humidity, air temperature at the air heater entrance, feed water inlet temperature, ash percentage in coal and heating value of coal from the expressions in Table 4. Using these expressions, the required corrections are found for the semi-bituminous coal and presented in Table 5. The corrected boiler efficiency is worked out to be 90.15%.

Table 5: Corrected Boiler Efficiency for Semi-Bituminous Coal

	Design	Actual Value	Corrections (%)
Total Moisture in Coal (%)	10	10.75	0.14
H2 in Coal (%)	2.48	2.92	0.6
Air absolute Humidity @60% RH (%)	0.03	0.02	-0.084
Air Temperature at APH inlet (^{o}C)	41.36	25.06	-0.53
Feed Water inlet Temperature (^{o}C)	274.9	277.8	0.03
Ash percentage in Coal (%)	45	29.15	-0.069
Heating Value of Fuel (kcal/kg)	3500	4410	-0.5^+
Total			-0.40
Corrected Boiler Efficiency (%)			90.15
$^+$HHV maximum C_f=-0.5 when x>>3824			

3. CYCLE HEAT RATE AND OVERALL EFFICIENCY

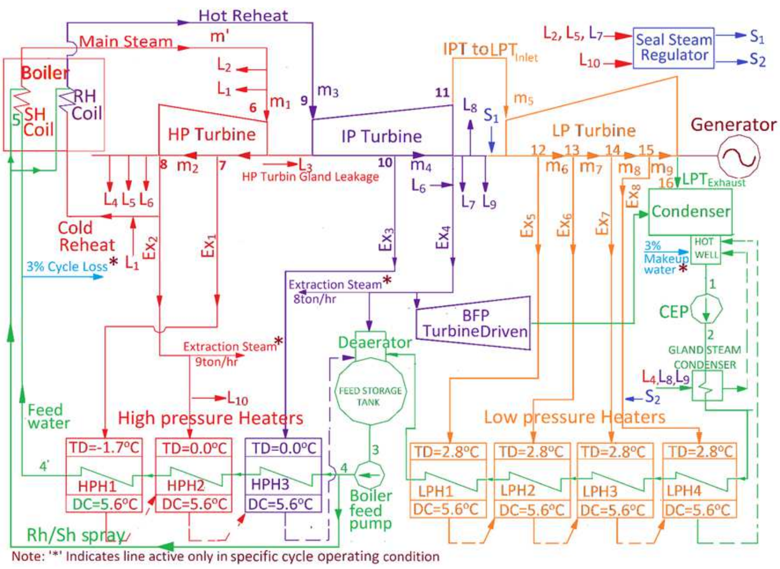

Figure-6: Heat Balance Diagram of a Typical 600 MW Plant Representing Mass Flow Rates m1 =m'-L1-L2-L3, m2=m1-Ex1-L4-L5-L6, m3=m2-Ex2+L1,m4=m3-Ex3-L7-L8-L9, m5=m4-Ex4+L6+L3, m6=m5-Ex5,m7=m6-Ex6, m8=m7-Ex7, m9=m8-Ex8

Using the heat balance diagram of Figure 6 cycle heat rate and overall efficiency of the unit are estimated. Figure 7shows temperature and entropy. Tables 6 and 7 give the mass flow rate, leakages, temperature, pressure, enthalpy for main design conditionsand various operating parameters for live operating plant. Heat rate is the energy required to produce one kWh power. Theoretically 1kWh equals3600kJ. So plant with 100% efficiency will have 3600kJ/kWh or 860kcal/kWh of heat rate. But due to heat losses in boiler,turbine and auxiliaries it is between 7400 to 9400 kJ/kWh[7]. Turbine cycle heat rate (TCHR) is the ratio of heat input to the cycle to the Net power output [8]:

$$\text{TCHR}=\frac{\text{Heat input to the Turbine cycle}}{\text{Net Power Output}}=\frac{\text{Main Steam Flow }(h_{MS}-h_{FW})+\text{CRH Flow }(h_{HRH}-H_{CRH})}{\text{Net Power Output}} \tag{9}$$

The net power output (P_{Net}) of turbine is power output times the generator efficiency:

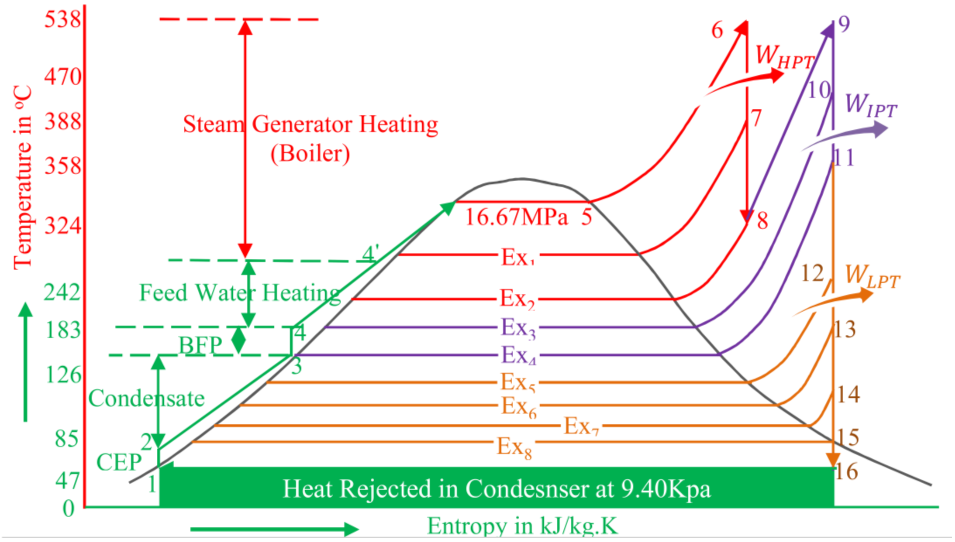

Figure 7: Temperature and Entropy Diagram

$$P_{Net}=P\times\eta_{generator} \tag{10}$$

Here $P=P_{HPT}+P_{IPT}+P_{LPT}$ (11)

The power output in HP turbine,

$$P_{HPT}=m_1(h_{MS}-h_{Ex1})+m_2(h_{Ex1}-h_{CRH}) \tag{12}$$

The power output in IP turbine,

$$P_{IPT}=m_3(h_{HRH}-h_{Ex3})+m_4(h_{Ex3}-h_{LPT\ in}) \tag{13}$$

The power out in LP turbine,

$$P_{LPT}=m_5(h_{LPT\ in}-h_{Ex5})+m_6(h_{Ex5}-h_{Ex6})+m_7(h_{Ex6}-h_{Ex7})+m_8(h_{Ex7}-h_{Ex8})+m_9(h_{Ex8}-h_{LPT\ Exhaust}) \tag{14}$$

Table 6: Desing Operating Parameters at 100%TMCR with Design Coal and Live Operating Parameters Near 100%TMCR with Semi-Bituminous Coal

Description (See Figure 6)	Design				Live			
	FlowRate T/h	Temp. ^{0}C	Pressure MPa	Enthalpy kJ/kg	Flow Rate T/h	Temp. ^{0}C	Pressure MPa	Enthalpy KJ/Kg
MS	1848.5	538	16.67	3397.2	1798.5	533.12	16.106	3391.57
CRH	1576.0	323.8	3.797	3033.3	1527.0	329.87	3.853	3046.08
HRH	1576.0	538	3.417	3537	1527.0	527.74	3.489	3514.64
FW	1848.5	274.9	16.67	1205.9	1686.0	277.8	18.655	1220.86
Ex_1	131.1	388.1	6.09	3147.7	134.2	395.16	6.114	3163.59
Ex_2	112.7	323.8	3.797	3033.3	105.3	324.16	3.676	3036.23
Ex_3	91.4	469.7	2.168	3398.9	74.4	465.62	2.183	3390.26
Ex_4	160.8	357.7	1.001	3174.7	96.1	348.94	1.021	3155.59
Ex_5	46.2	241.7	0.368	2948.5	46.2	269.33	0.368	3003.8
Ex_6	43.2	182.5	0.211	2834.5	43.2	191.86	0.211	2853
Ex_7	44.5	125.5	0.116	2725.9	44.5	125.5	0.116	2725.9
Ex_8	75.7	84.8	0.057	2614.7	75.7	84.8	0.057	2614.7
LPT inlet	1346.9	357.7	0.968	3174.1	1345.0	348.9	0.986	3155.19
LPT Exhaust	1139.1	48	0.0094	2383.6	1135.5	48.2	0.011	2373.48
To BFPT	65.4	357.7	1.001	3174.7	32.6	348.94	1.021	3155.59
SH Spray	0.0	-	-	-	110.0	-	-	-
Leakages(T/h): L_1=1.98; L_2=0.6; L_3=17.9; L_4=0.3; L_5=3; L_6=7, L_7=1.6; L_8=0.3; L_9=1.01; L_{10}=-2.7								

Using the design data in Table 6 and referring Figure 6, the net power output is evaluated as

P_{Net}=(180.5+152.8+274)×0.988=600MW andTCHR=1931.58 $\frac{kcal}{kWh}$.

Turbine efficiency, unit heat rate (UHR) and overall efficiency are evaluated from[9]

$$\text{Turbine Efficiency} = \frac{860}{\text{TCHR}}\times 100 = 44.52\% \tag{15}$$

$$\text{Unit heat rate (UHR)} = \frac{\text{TCHR}}{\text{Boiler Efficiency}} = 9187.53\ \text{kJ/kWh} = 2198\ \text{kcal/kWh} \tag{16}$$

$$\text{Overall Efficiency} = \frac{860}{\text{UHR}}\times 100 = 39.12\% \tag{17}$$

Similarily, the overall efficiency is evaluated for the operating conditions of Table 1 and presentedthe results in Table 7. It is noted that the heat rate is morewhen unit operates at less load or power ouput. Overall efficiency is maximum when heat rate is minimum. Unit heat rate for extraction steam condition is minimum and is similar to cogeneration.

Table 7: Power Output and TCHR, UHR, Overall Efficiency at Main Operating Conditions

Description (See Figure 6)	UOM	TMCR with 3% Make Up	VWO	80% TMCR	40% TMCR	ALL HP Heaters Out	No.1 HP heater Out of Service	Extraction Steam Condition
MS	T/h	1864.50	2028.00	1465.31	792.71	1618.90	1751.10	1997.10
Prs. /Temp	MPa/^{o}C	16.67/538	16.67/538	14.82/538	7.41/527	16.67/538	16.67/538	16.67/538
CRH	T/h	1581.09	1718.94	1266.83	704.14	1591.64	1606.92	1598.86
Prs. /Temp	MPa/^{o}C	3.8/324	4.13/333	3.07/322	1.68/335	3.94/333	3.87/327	3.82/323
HRH	T/h	1581.09	1718.94	1266.83	704.14	1591.64	1606.92	1598.86
Prs. /Temp	MPa/^{o}C	3.42/538	3.72/538	2.76/538	1.51/498	3.55/538	3.48/538	3.43/538
FW	T/h	1864.50	2028.00	1465.31	792.71	1618.90	1751.10	1997.10
Prs. /Temp	MPa/^{o}C	18.66/275	18.66/281	16.81/261	9.4/228	18.66/183	18.66/245	18.66/278
Ext $_1$	T/h	137.01	150.66	93.56	40.45	0.00	0.00	213.87
Prs. /Temp	MPa/^{o}C	6.12/389	6.67/399	4.91/385	2.74/401	6/391	6.23/393	3.82/323
Ext $_2$	T/h	117.50	127.07	82.04	35.87	0.00	115.86	154.22
Prs. /Temp	MPa/^{o}C	3.8/324	4.13/333	3.07/322	1.68/335	3.94/333	3.87/327	6.37/393

Ext $_3$	T/h	95.30	102.64	68.31	33.25	0.00	93.76	104.58
Prs. /Temp	MPa/^{o}C	2.17/469	2.36/469	1.76/471	0.97/435	2.33/475	2.21/470	2.15/468
Ext $_4$	T/h	166.77	177.34	120.58	49.10	166.02	161.51	252.32
Prs. /Temp	MPa/^{o}C	1/357	1.09/357	0.82/360	0.46/332	1.08/363	1.02/358	0.93/349
Ext $_5$	T/h	48.00	51.31	35.38	17.57	50.00	47.19	48.98
Prs. /Temp	MPa/^{o}C	0.37/241	0.4/241	0.3/244	0.11/221	0.4/246	0.38/242	0.34/234
Ext $_6$	T/h	44.79	47.65	33.43	16.72	46.73	44.05	45.45
Prs. /Temp	MPa/^{o}C	0.21/182	0.23/182	0.17/185	0.1/165	0.23/186	0.22/183	0.2/175
Ext $_7$	T/h	46.28	49.61	34.13	16.80	48.07	45.47	47.51
Prs. /Temp	MPa/^{o}C	0.21/125	0.13/125	0.1/127	0.06/110	0.13/129	0.12/126	0.11/119
Ext $_8$	T/h	78.05	86.74	53.14	18.03	84.27	77.95	76.72
Prs. /Temp	MPa/^{o}C	0.06/85	0.06/87	0.05/80	0.03/68	0.06/87	0.06/85	0.05/83
IPT to LPT	T/h	1342.25	1464.12	1096.23	631.54	1446.81	1374.19	1266.74
Prs. /Temp	MPa/^{o}C	0.98/357	1.07/357	0.81/360	0.46/332	1.06/363	1.01/358	0.92/349
LPT exhaust	T/h	1126.79	1230.47	941.79	564.08	1219.40	1161.18	1049.74
Enthalpy	kJ/kg	2.38	2.37	2.42	2.52	2.38	2.38	2.39
Total Gland Leakage	T/h	22.00	24.00	17.00	11.00	22.00	22.00	22.00
Power Output (MWh)		600.2	648.6	480.1	240.0	600.0	600.1	605.7
TCHR (kJ/kWh)		8034.1	8055.9	8262.4	9272.1	8321.3	8133.8	7695.7
UHR (kJ/kWh)		9142.2	9166.9	9402.0	10550.8	9468.9	9255.6	8757.1
Overall Efficiency (%)		39.3	39.2	38.2	34.1	38.0	38.8	41.1

Cost per unit power produced is [3, 7]

$$\text{Cost Per kWh}=\frac{\text{TCHR}}{\eta_{\text{boiler}}}\times\text{Cost of Coal per kcal} \tag{18}$$

4. HEAT RATE DEVIATION

When thermal performance parameters of the unit deviate from the main operating conditions, their influence on the unit heat rate (UHR) can be found using the heat rate deviation method [https://www.scribd.com/document/379461735/4-EEMS]. As in [9] correction factors for the 600MW turbine are provided in Table 8

$$\text{Corrected Heat Rate}=\text{Heat Rate}\Big/\left(1+\frac{C_f}{100}\right) \tag{19}$$

Table 8: Expressions for the Unit Heat Rate Correction

Variable (x)	ξ	Correction (C_f)
Main Steam Pressure (MPa), x∈ [15, 18]	-13.3903+0.815262x	0.0844ξ2 - 0.8359ξ + 0.1657
Main Steam temp (0C), x∈ [522, 549]	-37.4137+0.0699032x	-0.3821ξ + 0.0762
Reheater Pressure Drop (MPa), x∈ [7, 12]	-35.5767+0.0663746x	-0.4018ξ + 0.0555
Reheat temperature(0C), x∈ [522, 552]	-3.82108+0.402317x	0.2407ξ - 0.0445
Condenser Back pressure (kPa), x∈ [5.3, 14.7]	-2.12746+0.213783x	0.3411ξ2 + 3.2634ξ + 0.3864
BFPT Steam Flow (T/h), x∈ [32.75, 34]	31.7498-0.950661x	-0.0011ξ2 - 0.0892ξ + 0.0592
SH spray ratio, x∈ [0, 8]	-1+0.248437x	-0.104ξ2 + 1.115ξ + 1.199
HPH TD (0C), x∈ [-3,1.6]	-0.200787-0.40058x	-0.0451ξ + 0.0232
HPH DC (0C), x∈ [2,10]	1.49894-0.250073x	-0.0078ξ + 0.0008
Control Valve#3 open (%), x∈ [32,100]	-1.86883+0.0286883x	-0.1813ξ2 - 0.1942ξ + 0.3784
Control Valve#4 open (%), x∈ [0,48]	-1.04251+0.0423932x	-0.0651ξ2 + 0.1486ξ + 0.2148

Table 9: Cost of Heat Rate Deviation for Live Operating Plant near 100%TMCR

Description (see Figure 6)	Design	Actual	Correction Factor, C_f	Corrected UHR+	Heat Rate Deviation++	Cost of Heat Rate Deviation (Crores.)
Throttle pressure, MPa	16.67	16.11	0.39	2189	9.2	1.04
Throttle temperature, ^oC	538	533.12	0.13	2195	2.9	0.35
RH Temp. ^oC	538	527.74	0.28	2192	6.1	0.75
RH pressure drop %	10	9.45	-0.05	2199	-1.1	-0.13
Condenser pressure. Kpa	9.4	10.8	0.99	2174	23.9	2.63
Spray water flow ratio	0	6.11	1.75	2161	36.7	4.61
RH spray flow. Ratio	0	0	0	2198	0.0	-
Make up flow, T/h	0	0	0	2198	0.0	-
Valve position, CV1-3	100	100	0	2198	0.0	-
Valve position, CV4	0	30.65	0.25	2193	5.5	0.67
Speed, rpm	3000	2998.2	0	2198	0.0	-
HP heater TD, ^oC	-1.7	-1.2	0.01	2198	0.2	0.03
HP heater DC. ^oC	5.6	29	0.01+++	2198	0.2	0.03
Condenser sub cooling, ^oC	0	0	0	2198	0.0	-
TDBFP steam flow, T/h	32.7	32.63	-0.01	2198	-0.2	-0.03
Unit aging, month	10	10	0.5	2187	10.9	1.34
Cost Reduction per annum(Crores.)					92.4	11.28
+Corrected UHR, CUHR= UHR/(1+C_f/100) ++ Heat rate deviation= UHR-CUHR +++HP heater DC maximum possible C_f=0.01 when x>>10						

Using the design and live plant parameters of Table 6 and correction factors in Table 8, the heat rate deviation calculated in Table 9 is 92.4. Throttle pressure andtemperature in Table 9 indicate the main steam pressure andtemperature at inlet to HP turbine. RH temperature andpressure indicate the hot reheat temperature inlet to IP turbine. Pressure drop due to reheating of CRH (cold reheat) to HRH (hot reheat) can be found from

$$\text{Reheat Pressure Drop}=100-\frac{\text{CRH pressure}}{\text{HRH pressure}}\times 100=100-\frac{3.489}{3.853}\times 100=9.45 \quad (20)$$

SH spray is used to control the temperature and pressure of the main steam line. Using the flow of super heater spray(110T/h) and themain steam flow (1798.85T/h), one can obtain

$$\text{Spray water flow ratio (\%)}=\frac{\text{SH spreay flow}}{\text{Main steam flow}}\times 100=\frac{110}{1798.85}\times 100=6.11 \quad (21)$$

Using the flow of re-heater spray (0 T/h) andhot reheat flow (1527 T/h),one can obtain

$$\text{RH spray flow ratio (\%)}=\frac{\text{RH spray flow}}{\text{Reheat steam flow}}\times 100=0 \quad (22)$$

The de-mineralized water is added to the plant cycle due to water and steam leakages. Generally 3% make-up water is added, which is 3% of Throttle Flow (= 3%×1798.85=53.96 T/h). Control valve (CV) position indicates the percentage opening of 4 control valves on HP turbine. In general first 3 control valves (CV_1, CV_2, CV_3) are fully open in most conditions, whereas CV_4fully opens only in 100% BMCR or VWO condition. Figure 8 shows thermal profile of feed water heater.

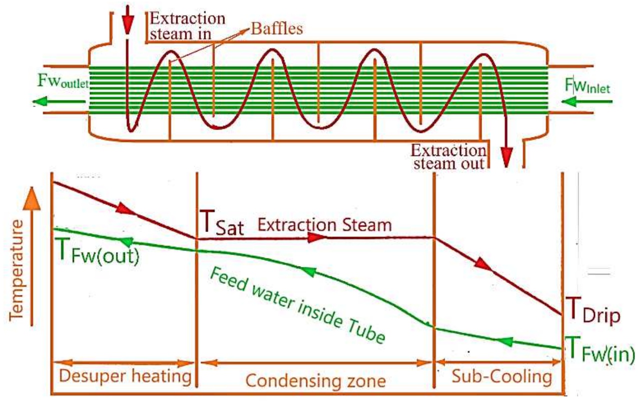

Figure 8: Feed Water Heater Thermal Profile

$$\text{Heater TD}=T_{sat}-T_{Fw(out)}, \tag{23}$$

is the temperature difference between extraction steam saturation temperature (T_{sat}) at inlet pressure and thefeed water outlet temperature ($T_{FW(out)}$).

$$\text{Heater DC}=T_{Drip}-T_{Fw(in)}, \tag{24}$$

is the heater drain cooler temperature difference between heater drain outlet temperature (T_{Drip}) and feed water inlet temperature ($T_{FW(in)}$).

When cooling water flow through condenser is higher than its design,condenser sub-cooling increases condenser back pressure and reduces heat transfer due to formation of water droplets and air bubbles on condenser tube bundle and baffle plates. TDBFP or BFPT steam flow indicates the amount of steam flow to turbine driven boiler feed pump. In a typical 600MW unit, two numbers of TDBFP are used to pump the feed water after unit start-up. Boiler feed pump driven by motor is kept idle. Usage of TDBFP reduces power consumption, and can have safe and flexibility operations. Unit aging is counted from the time when unit achievessynchronization mile stone (i.e. Turbine runs at 3000rpm). Cost of semi-bituminous coal is Rs.1024/ton [https://www.coalindia.in/].

$$\text{Fuel Cost}=\frac{\text{Cost of Coal per kg}}{GCV_{Coal}}=0.000232\,\frac{\text{Rs.}}{\text{kcal}} \tag{25}$$

Cost of heat rate deviation per annum= Heat rate deviation×net generation×fuel cost×plant load factor

$= 92.4 \times 600000 \times 24 \times 365 \times 0.000232 \times 1=$ 11,28,00,927 Rs. $\approx$ 11.28 crores

Plant load factor (PLF)is taken as unity assuming 100% load on the plant through the year. Table 10 givesthe cost of heat rate deviation for live operating unit near 100%TMCR for different types of coals in India. The cost of heat rate deviation is found to be minimum for Indian lignite coal due to low fuel cost and reasonably high GCV value.

Table 10: Cost of Heat Rate Deviation for Live Operating Unit near 100% TMCR for Various Coals

Description	Design Coal	Semi-Bituminous Coal	Bituminous Coal	Indian Lignite Coal	Worst Coal
GGV of coal (Kcal/Kg)	3500	4410	5800	4300	3140
Coal cost per ton (Rs.)	817	1024	2317	955	748
Coal cost per Kcal (Rs.)	0.0233	0.0232	0.03995	0.02221	0.02382

Heat rate deviation (Kcal/kWh)	92.43	92.43	92.43	92.43	92.43
Cost (Crores)	11.34	11.28	19.41	10.79	11.57

Increase in coal input per annum= $\frac{\text{Cost of Heat Rate Deviation per annum}}{\text{Coal cost per ton}}$ = 11,28,00,927 /1024= 1,10,157 tons

CO_2produced per kg of fuel=%C in fuel× $\left(\frac{\text{molecular weight of } CO_2}{\text{atomic weight of Carbon}}\right) = 0.4381 \times \frac{44}{12} = 1.6064$kg/kg of fuel

Increase in CO_2 per annum=Increase in Coal input per annum×CO_2 produced of ton coal

$= 1{,}10{,}157 \times 1.6064$ Ton $=$ 1,76,953 Ton per annum

Table 11 gives the possible CO_2reduction for live operating unit near 100% TMCR forvarious coals. When carbon in coal completely burns it converts to CO_2.CO and CO_2 are produced when incomplete combustion takes place.

CO produced per kg of fuel=m_{dfg}×CO in ppm×10^{-6} $= 7.44 \times 40 \times 10^{-6} = 0.000297$ Kg/Kg of fuel

Since the carbon monoxide produced is very less compared to that of $CO_2$and hence, it is neglected.

Similarily,cost of heat rate deviation iscalculated for the coals in Table 2 and the operating parameters of Table 8.

Table 11: Possible CO_2 Reduction for Live Operating Unit near 100% TMCR

Description	Design Coal	Semi-Bituminous Coal	Bituminous Coal	Lignite Coal	Worst Coal
GCV(Kcal/kg)	3500	4410	5800	4300	3140
Carbon (%)	35.64	43.81	59	37	32.2
Coal cost per ton (Rs.)	817	1024	2317	955	748
Cost of heat rate deviation (Cr./year)	11.34	11.28	19.41	10.79	11.57
Coal wasted per annum (Tons)	1,38,798	1,10,157	83,757	1,12,975	1,54,711
CO_2 produced per kg coal	1.31	1.61	2.16	1.36	1.18
CO2 reduction per annum (Ton)	1,81,381	1,76,953	1,81,195	1,53,270	1,82,662

5. OTHER APPLICATIONS

In combined cycle power plant unit heat rate is the ratio of heat input in a gas turbine to the gross power output of gas & steam turbines, power output & heat rate deviation procedures for steam turbine part remain same. The overall efficiency of combined cycle plant is above 48%. The power output of gas turbine and efficiency of the Heat recovery steam generator can be evaluated as per ASME PTC 4.4 [10].

In cogeneration for evaluation of the unit heat rate, the heat carried away by the process steam is to be deducted from heat input to the cycle while adding heat input by make-up water for all power plants, which decreases net heat input. The decrease net heat input leads to decrease in the unit heat rate and increase in overall efficiency.

In a nuclear power plant the boiler in coal fired steam power plant is replaced with a nuclear reactor. The reactor has 13% energy loss due to radiation and circulation loss, whereas49% energy loss in steam turbine and condenser. when reactor efficiency is given It should be noted that the overall efficiency and the unit heat rate evaluation procedures are same for super critical/ultra mega power projects. When changes take place in the fuel input to the power plant, its furnace size and combustion mechanism in burner system are to be changed accordingly. Fluidized bed combustion is preferred

against pulverized fuel wall firing for the fuels having high percentage of solid waste products [http://drtlud.com/BEF/proximat.htm].

6. CONCLUSIONS

The overall plant efficiency is found to increase with the decreasingunit heat rate (UHR). The cost per kWh is also decreased. For less UHR, the cost of heat rate deviation can be minimized for highmain steam throttle temperature and pressure. Superheat spray and reheater spray water utilization need to be minimized or to be avoided. Condenser back pressure need to be maintained below 9.4kPa to achieve the cost saving of 11.3crores per annum. Also this cost per annum can be minimizedthrough lowcost coal having highGCV. CO_2 Production can also be minimized using coal having high GCV and less Carbon Content as in lignitecoal. As the efficiency of combined cycle plant is high when compared to coal fired boiler power plant, coal gasification is preferred instead of direct coal firing. The fuel from coal gasification can be used in combined cycle plants, which minimizes environmental pollution due to ash absent in the combustion products.

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